PM_{10} SIP/Maintenance Plan Evaluation Report: Holly Refining and Marketing Company – Woods Cross, LLC.

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Holly Refinery

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Implementation Plan (SIP); to address the Salt Lake County PM_{10} Nonattainment Area (SLCNA). This document specifically serves as an evaluation of the Holly Refinery.

<u>Note on document identification:</u> The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Sections IX.H.1-4 of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report. However, see Section 7.0 of this document for some clarification.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Holly Refinery
Address: 393 South 800 West, Woods Cross, Utah, Davis County
Owner/Operator: Holly Refining & Marketing Company – Woods Cross, LLC
UTM coordinates: 4,526,227 m Northing, 424,000 m Easting, Zone 12

1.2 Facility Process Summary

The Holly Refinery (Holly) is a petroleum refinery capable of processing 60,000 barrels per day of crude oil, primarily heavier black wax and yellow wax crudes from eastern Utah. The source consists of two FCCUs, both controlled with wet gas scrubbers. A single sulfur recovery unit controls the sulfur content of the fuel gas. The source also has the usual assorted heaters, boilers, cooling towers, storage tanks, flares, and related fugitive emissions – primarily VOCs.

The two FCCUs are both complete burn units without cokers. There are no cogeneration units present. The refinery currently operates without flare gas recovery.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the Holly Refinery:

- Fluid Catalytic Cracking Unit (FCCU) #1, controlled with a wet gas scrubber (WGS)
- FCC Feed Heater, 68.4 MMBtu/hr process furnace, fired on plant gas, restricted to 39.9 MMBtu/hr, equipped with low NO_x burners (LNB)
- Reformer charge and reheater furnace/waste heat boiler, 54.7 MMBtu/hr process furnace, fired on plant gas
- Prefractionator Reboiler Heater, 12.0 MMBtu/hr process furnace, fired on plant gas
- Reformer Reheat Furnace, 37.7 MMBtu/hr process furnace, fired on plant gas
- HF Alkylation Regeneration Furnace, 4.4 MMBtu/hr process furnace, fired on plant gas
- HF Alkylation Depropanizer Reboiler, 33.3 MMBtu/hr process furnace, fired on plant gas
- Crude Furnace #1, 99.0 MMBtu/hr process furnace, fired on plant gas, equipped with next generation ultra-low NO_x burner (NGULNB)
- Distillate Hydrosulfurization (DHDS) Unit Reactor Charge Heater, 8.1 MMBtu/hr process furnace, fired on plant gas
- DHDS Stripper Reboiler, 4.1 MMBtu/hr process furnace, fired on plant gas
- Asphalt Mix Heater, 13.2 MMBtu/hr process furnace, fired on plant gas
- Hot Oil Furnace, 99 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and selective catalytic reduction (SCR) system
- Straight Run Gas Plant (SRGP) Depentanizer Reboiler, 24.2 MMBtu/hr process furnace, fired on plant gas
- Naphtha Hydrodesulphurization (NHDS) Unit Reactor Charge Furnace, 50.2 MMBtu/hr process furnace, fired on plant gas, equipped with NGULNB
- Isomerization Reactor Feed Furnace 6.5 MMBtu/hr process furnace, fired on plant gas
- Sulfur Recovery (SRU) with Tailgas Incinerator
- Distillate Hydrodesulfurization Treatment (DHT) Reactor Charge Heater, 18.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB
- Gas Oil Hydrocracking (GHC) Unit Reactor Charge Heater, 14.9 MMBtu/hr process furnace, fired on plant gas, equipped with ultra-low NO_x Burners (ULNB)
- Fractionator Charge Heater, 47.0 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- Fractionator Charge Heater, 42.1 MMBtu/hr furnace, fired on plant gas, equipped with ULNB
- Reformate Splitter Reboiler Heater, 21.0 MMBtu/hr heater, fired on plant gas, equipped with ULNB
- Crude Unit Furnace, 60.0 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB

- FCCU #2, controlled with WGS and LoTOx
- FCC Feed Heater 45 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- Hydrocracker/Hydroisom Unit Reactor Charger Heater, 99.0 MMBtu/hr reactor charger heater, fired on plant gas, equipped with LNB and SCR
- Hydrogen Reformer Feed Furnace, 123.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and SCR
- Hydrogen Reformer Feed Furnace, 123.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and SCR
- Vacuum Furnace Heater, 130.0 MMBtu/hr heater, fired on plant gas, equipped with LNB and SCR
- Boiler #4, 35.6 MMBtu/hr boiler, fired on plant gas
- Boiler #5, 70.0 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- Boiler #8, 92.7 MMBtu/hr boiler, fired on plant gas, equipped with LNB and SCR
- Boiler #9, 89.3 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- Boiler #10, 89.3 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- Boiler #11, 89.3 MMBtu/hr steam boiler, fired on plant gas, equipped with LNB and SCR
- Cooling Towers
- Flares
- Tank Farm
- Loading/Unloading
- Emergency Equipment (Diesel)
- Emergency Equipment (Natural Gas)

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the refinery, rather it is a listing of all significant emission units or emission unit groups (such as the tank farm).

1.4 PM2.5 SIP New Equipment

As part of the RACT requirements for the PM2.5 SIP, Holly is in the process of making equipment upgrades which will be completed prior to the attainment demonstration date of the new maintenance plan (January 1, 2019). Although these upgrades are not yet installed, the new equipment has been included in the modeled attainment demonstration; by including the effects of the equipment on total emissions from the refinery.

Holly is adding a second WGS unit to control emissions from the newly installed FCCU #2. A new more efficient cooling tower will be installed, and several compressor engines will be converted to electric operation. Both of these changes have been included in the emission calculation spreadsheet used as primary input for the attainment demonstration model. The new WGS controls particulates, NOx and SO2 emissions, while the conversion of the compressor engines has completely eliminated combustion emissions from those sources.

One additional control system is the requirement to install and operate a flare gas recovery system or equivalent flare gas minimization process. This system must be installed an operational no later than January 1, 2019 – again, before the attainment demonstration date. The requirement for this system is found within the refinery general requirements of Section IX.H.11 of the SIP, specifically IX.H.11.g.v.B. Although no equivalent requirement was brought forward into the PM10 Section of the new maintenance plan, Holly (as with all the refineries) does have additional requirements in its listing in Section IX.H.2 to account for monitoring of flare gas flow – either to demonstrate flare gas recovery, or to account for flaring emissions as part of the overall daily

Caps. The monitoring requirements will address both PM10 and PM2.5 needs. See Items 5 and 6 below for additional details.

1.5 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, Holly's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	54.45
SO_2	131.03
NO_x	208.46

The current PTE values for Holly, as established by the most recent AO issued to the source (DAQE-AN101230041-13) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	147.8
SO_2	110.3
NO_x	341.1

However, please see the discussion in Section 2.0 (and Table 3) below for further details on Holly's PTE value.

2.0 Modeled Emission Values

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Generally for each refinery, beginning with the PTE values listed in Table 2 (from the most recent approval order issued to each source), these values were "trued-up" by including the expected effects from implementation of RACT from the PM2.5 SIP. This yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Where gaseous fuels, such as natural gas or refinery fuel gas, were combusted, filterable-only emissions were converted to a filterable+condensable emission value by multiplying the filterable rate by 4. Liquid fuels, such as diesel fuel #2, were converted using the latest AP-42 emission factors. Processes such as cooling towers, which emit largely filterable-only emissions, were not adjusted. Other processes were adjusted, as needed, on a case-by-case basis using the best data available – primarily the latest stack test information.

For the Holly Refinery specifically, these additional steps were not required. The AO issued to Holly in 2013 included the expected application of RACT as well as the assumption that both filterable and condensable emissions would be limited. Therefore, for the Holly Refinery, no change occurs between the values in Table 2 and the Modeled Emission Values listed in Table 3, as shown below:

Table 3: Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	147.8
SO_2	110.3
NO_x	341.1

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM10 SIP sources – including the refineries in general, and the Holly Refinery in specific. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11-13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: significant from the standpoint of PM10 control, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

Holly is a previously listed SIP source. In the original PM_{10} SIP, Holly was listed in Subsection IX.H.2.b.OO{OS} as Phillips 66 Company – Woods Cross. As a listed source there were several requirements and conditions that applied to the facility.

In addition, Holly is also a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.12.k). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the December 3, 2014 PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.k. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements{OS}

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a{OS} applied to the listed sources found in Utah County, while those found at IX.H.2.a{OS} applied to the listed sources found in Salt Lake and Davis County. As the then Phillips Refinery was located in Davis County, only the general requirements of IX.H.2.a{OS} applied. However, except for the additional requirements found under IX.H.2.a.M{OS} for petroleum refineries and the specific fuel requirements of IX.H.2.a.N{OS}, the two subsections are essentially identical.

2.a.A. Stack Testing{OS} – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which serves the same purpose.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which serves the same purpose.

2.a.C. Visible Emissions (cont.)$^{\{OS\}}$ – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations$^{\{OS\}}$ – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

2.a.E. Recordkeeping Requirements$^{\{OS\}}$ – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders$^{\{OS\}}$ – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance$^{\{OS\}}$ – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program, under R307-401-4(1).

2.a.H. Future Modifications$^{\{OS\}}$ – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program, under R307-401-3(1)(b).

2a.I. Unpaved Operational Areas$^{\{OS\}}$ – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the fugitive dust rules of R307-205 and R307-1-4.5, or the most recent federally approved fugitive dust rule.

2.a.J. Actual Emissions$^{\{OS\}}$ – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsections IX.H.1-4 of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed$^{\{OS\}}$ – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions$^{\{OS\}}$ – established that the definitions contained in R307 apply to subsection IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.N. Specific Fuel Requirements for Coal and/or Oil$^{\{OS\}}$ – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.2 Original SIP Petroleum Refinery Requirements

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections, owing to the overall length and complexity.

2.a.M.A. Sulfur Recovery Units (SRUs){OS} – established the requirement for 95% efficient SRUs, no burning of liquid fuel oil except during natural gas curtailments, use of low-SO_x catalyst to attain a 9.8 kg SO_2/1000 kg coke burnoff in FCC units, amine and sour water overhead streams shall also be processed in the SRU. These conditions currently remain in effect. The SO_2 limit is largely irrelevant as the limitation in SIP subsection IX.H.1.g.i.A.I is based on 40 CFR 60, Subpart Ja, and is more stringent. The other three requirements: 95% efficient SRUs, no burning of liquid fuel oil, & amine and sour water overhead streams being processed in the SRU, shall be retained. These three conditions are found at SIP subsections IX.H.1.g.iii, IX.H.1.g.iv, and IX.H.1.g.iii, respectively.

2.a.M.B. Routine Turnaround Periods{OS} – established exclusion periods when routine turnarounds of the SRUs could be performed, and the procedure for scheduling one of these periods. These conditions are no longer required. Each of the refineries has agreed to incorporate alterative language which supersedes these requirements. In Holly's specific case, the refinery has opted to install two WGS systems. These systems are sized such that all additional emissions from a SRU turnaround can be accommodated within the established 24-hour emission Caps – including all flaring and additional SO_2.

2.a.M.C.1. Compliance Demonstration part 1{OS} – established that SRU turnaround emissions and flaring emissions are not included in either the daily (24-hour) or annual compliance demonstrations. As with 2.a.M.B{OS} above, this requirement is no longer required. Each refinery has agreed to alternative language regarding SRU turnarounds. All flaring emissions have been included in the 24-hour emission Caps for each listed refinery. Further, flares are also addressed with SIP subsection IX.H.1.g.v.B which covers flare gas recovery systems.

2.a.M.C.2. Compliance Demonstration part 2{OS} – established how the daily (24-hr) emissions limits (Caps) would be determined, including recordkeeping and reporting requirements. This subsection has since been superseded by the individual source's SIP subsection (for Holly, this would be Section IX.H.2.f) which establishes the 24-hour emission limits, and the monitoring, recordkeeping and reporting requirements associated with those limits.

2.a.M.C.3. Compliance Demonstration part 3{OS} – established a methodology for how emission limits could be modified/adjusted as necessary. This subsection is no longer required, as this procedure is no longer followed.

2.a.M.C.4. Compliance Demonstration part 4{OS} – also established that annual emissions for refineries followed a process essentially identical to the rolling 12-month process outlined above in 2.a.D{OS}. This subsection is no longer required as the specific requirement to track annual emissions is no longer needed with the removal of the annual PM10 standard.

2.a.M.D. Process Flaring Emissions and Routine Turnaround Emissions{OS} – established that both sets of emissions were included in the modeled attainment demonstration. This subsection is no longer required, as a new attainment demonstration has been performed and both process flaring and routine turnaround emissions are handled differently in the new maintenance plan. See SIP subsection IX.H.1.g.v.B which covers flare gas recovery systems. SRU routine turnarounds requirements have been removed from the new maintenance plan.

3.3 Original SIP Source Specific Requirements

Individual source requirements:

2.b.OO.1.{OS} This subsection was a listing of the equipment at the refinery – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection does not match the current equipment installed and operating at the refinery and would represent a significant step backwards in emission control and refining technology.

2.b.OO.2.{OS} Basis for SO_2 Emission Limitations – A) established the SO_2 daily and annual emission Caps. B) established the sources included in the SO_2 emissions Caps. C) established that the SO_2 emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.B.OO.2.C) {OS}.], and that the quantity of each fuel burned would need to be monitored/recorded appropriately. D) was supposed to establish individual point source limitations for specific TCC emission units and the SRU tail gas incinerator (these were never revisited in the context of the SIP). E) established that stack testing would be performed as outlined in SIP subsections 2.b.OO.5{OS}, 2.a.A{OS} and 2.1.M{OS}. F) established that the flares were not included in the SO_2 Caps, and also not regulated for SO_2 emissions.

This subsection has since been superseded by the SIP subsection which establishes new plantwide SO_2 daily (24-hour) emission Caps (for Holly, this would be Section IX.H.2.f.iii). These new SO_2 emission Caps cover all emission units at the refinery – including the flares – so no emission unit is excluded. The new SO_2 emission Caps are significantly lower than the original Caps (see the comparison in Table 4 below). Although no annual standard for PM10 remains, the anticipated annual numbers have been included for easy comparison with the original SIP values. The compliance methodology included in SIP subsection IX.H.2.f.iii also includes the calculation of amount of fuel burned multiplied by the emission factor for each fuel type – although these emission factors have been updated as needed. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

2.b.OO.3.{OS} Basis for the NO_x Emission Limitations – Similar to the SO_2 limitations above: A) established the NO_x daily and annual emission Caps. B) established the sources included in the NO_x emissions Caps. C) established that the NO_x emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.B.OO.3.C){OS}.], and that the quantity of each fuel burned would need to be monitored/recorded appropriately. D) established that the flares were not included in the NO_x Caps, and also not regulated for NO_x emissions.

This subsection has since been superseded by SIP subsection IX.H.2.f.ii which establishes new plantwide NO_x daily (24-hour) emission Caps. As with the SO_2 emission Caps, these new NO_x

emission Caps cover all emission units at the refinery – including the flares. The new NO_x emission Caps are also lower than the original Caps (again, the table also includes the expected annual emission values as a convenient comparison with the original SIP emissions). Again, the compliance methodology included in SIP subsection IX.H.2.f.ii uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

2.b.OO.4.{OS} Basis for the PM_{10} Emission Limitations – As with both the SO_2 and NO_x limitations listed above: A) established the PM_{10} daily and annual emission Caps. B) established the sources included in the PM_{10} emissions Caps. C) established that the PM_{10} emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.B.OO.3.C){OS}.], and that the quantity of each fuel burned would need to be monitored/recorded appropriately. D) established an individual point source limitation for the TCC lift air heater/circulation system. E) established that stack testing would be performed as outlined in SIP subsections 2.b.OO.5{OS}, and 2.a.A{OS}. F) established that the flares and several compressor engines were not included in the PM_{10} Caps, and also not regulated for PM_{10} emissions.

This subsection has since been superseded by SIP subsection IX.H.2.f.i which establishes new plantwide PM_{10} daily (24-hour) emission Caps. As with both the SO_2 and NO_x emission Caps, these new PM_{10} emission Caps cover all emission units at the refinery – including the flares. While the compressor engines are technically also included, the majority of these engines have either been replaced with electric motors or had the gas-fired drivers replaced with electric drivers. This renders these engines as non-emitting units. The new PM_{10} emission Caps are also lower than the original Caps, on both an annual and 24-hour basis (annual values listed for comparison purposes as with SO2 and NOx). As before, the compliance methodology included in SIP subsection IX.H.2.f.i uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

Table 3: Comparison Table – Old SIP Caps vs New SIP Caps

	SO_2 Original	**SO_2 New**	**NO_x Original**	**NO_x New**	**PM_{10} Original**	**PM_{10} New**
Annual	1,762.0*	110.3	693.0	341.1	160.9$	147.8&
Daily (24-hr)	4.705	0.31	2.20	2.09	0.441$	0.42&

* SIP Cap sources only (total annual emissions are listed in 2.b.OO.6 below)
$ filterable emissions only
& includes condensable emissions

2.b.OO.5.{OS} Stack Testing Requirements – established which point sources were required to comply with specific emission limitations (established in preceding paragraphs), the test method to be used to verify compliance (including CEMs if applicable), and the frequency of testing and/or monitoring.

This subsection has since been superseded by SIP subsection IX.H.2.f which establishes new monitoring, recordkeeping and reporting requirements for each of the limits listed in that subsection. The test methods to be used for each specific pollutant are listed in subsection IX.H.1.c. While details on the use of CEMs is covered in subsection IX.H.1.f.

2.b.OO.6.{OS} Annual Emissions – established total annual emissions for the entire refinery. These annual emissions differed from the SIP Cap totals in one important aspect; the SO_2 total included values for SRU turnaround emissions (136 tpy), and estimated process flaring emissions (118 tpy). Thus, total annual SO_2 emissions were established at 2,016.0 tons/yr.

This subsection has since been superseded by SIP subsections IX.H.2.f.i, IX.H.2.f.ii and IX.H.2.f.iii which establishes new emission Caps for each of the pollutants of concern (PM_{10}, NO_x and SO_2). These emission Caps include the potential emissions from all emission units at the refinery, including the flares.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – either in the Petroleum Refinery provisions of IX.H.1.g, or the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – General Refinery Requirements

The new maintenance plan will incorporate several new requirements that apply specifically to those petroleum refineries listed in Sections IX.H.2 and IX.H.3 of the SIP. Some subsections of IX.H.1.g also apply more broadly and could affect additional petroleum refineries in addition to those listed in the Source Specific sections which follow. Where this greater applicability exists for a particular condition or limitation, such will be noted in the discussion for that requirement.

IX.H.1.g.i.A This condition covers SO_2 emissions from fluidized catalytic cracking units (FCCUs). The limit is 50 ppmvd @ 0% excess air on a 7-day rolling average basis, as well as 25 ppmvd @ 0% excess air on a 365-day rolling average basis.

The condition is based on 40 CFR 60 Subpart Ja, and includes the same limitation found in that subpart. Compliance is demonstrated by CEM, as outlined in 40 CFR 60.105a(g) – also from Subpart Ja.

IX.H.1.g.i.B This condition addresses PM emissions from FCCUs. The limit is 1.0 lb PM per 1000 lb coke burned. The emission limit applies on a 3-hour average basis.

The emission limit is derived from 40 CFR 60 Subpart Ja, although Subpart Ja does not specifically state that the limit applies on a 3-hour average. Instead it states that compliance will be demonstrated via a performance test using Method 5, 5b or 5f, using an average of three 60-minute (minimum) test runs.

Compliance is demonstrated by stack test as outlined in 40 CFR 60.106(b). This stack testing procedure is from Subpart J, rather than Subpart Ja. The equations utilized and reference methods involved are identical between the two subparts; however, the protocol to follow for testing is much more direct and straightforward in §60.106(b). The condition also requires the installation of a continuous parameter monitoring system (CPMS) to monitor and record operating parameters for determination of source-wide PM_{10} emissions for inclusion in the 24-hour PM_{10} Cap (see the individual source specific requirements of IX.H.2 for details on these Caps).

IX.H.1.g.ii This condition limits the H_2S content of gases burned within any refinery located within (or affecting) an area of $PM_{2.5}$ nonattainment. The limit is 60 ppm H_2S or less as described in 40 CFR 60.102a on a rolling average of 365 days.

As the $PM_{2.5}$ nonattainment areas encompasses the entirety of the PM_{10} maintenance areas this condition potentially affects more than just the four refineries listed in IX.H.2. There is at least one minor source refinery (Silver Eagle Refinery) which is affected by this requirement. The Silver Eagle Refinery was previously listed in the original SIP as Crysen Refining, Inc., but was delisted as the source is no longer a major source.

Compliance is demonstrated through continuous H_2S monitoring, as outlined in 40 CFR 60.107a. Both the limitation and the compliance methodology are based on 40 CFR 60 Subpart Ja.

IX.H.1.g.iii This condition requires the installation of SRUs that are 95% effective in removing sulfur from the streams fed to the unit; or SRUs that meet the SO2 emission requirements of Subpart Ja. The amine acid gas and sour water stripper acid gas shall be processed in the SRU(s).

This is part of condition 2.a.M.A{OS} brought forward from the original SIP. No other requirement has specifically superseded this condition, so the language has been incorporated herein.

Compliance shall be demonstrated by daily monitoring of flows to the SRUs (flow rate) and SO2 concentration in the exhaust stream (via CEM). Compliance shall be determined on a rolling 30-day average. As the specific compliance methodology was never outlined in the original SIP condition, and not clarified in any of the original specific source requirements, this requirement attempts to address this deficiency.

Small changes in the language of this condition were made to accommodate differences between the various refineries as they exist today, and to clarify the original intent of the requirement. The Holly refinery has combined the exhaust flows from the SRU and the FCCU so that they are controlled jointly by a wet gas scrubber. This makes monitoring of the SO2 concentration from only the SRU exhaust highly difficult. However, past testing has demonstrated that a 95% level of control across the SRU results in SO2 emissions in excess of the Subpart Ja emission standard. Therefore, meeting this emission standard will represent an equivalent or greater level of control. With respect to the amine acid gas and sour water stripper gas, this new language clarifies that it is the acid gas from these two processes that needs to be sent to the SRU, not all potential streams – some of which may be liquid streams which cannot be handled by the SRU.

IX.H.1.g.iv This condition disallows the burning of liquid fuel oil except during natural gas curtailments and/or as specified in IX.H.2 or IX.H.3.

This is an additional part of condition 2.a.M.A$^{\{OS\}}$ brought forward from the original SIP. As with the SRU requirement addressed in the previous condition, this condition was also never superseded. The language has been incorporated herein. Specifically disallows the burning of fuel oil in refinery heaters and boilers. Specific language in the individual source requirements of IX.H.2 (and potentially IX.H.3) allows for the use of diesel-fired emergency generators and similar emergency use equipment outside of natural gas curtailment periods.

IX.H.1.g.v This condition establishes new requirements on hydrocarbon flares.

It states that all hydrocarbon flares (defined as all non-dedicated SRU flare and header systems and all non-HF flare and header systems) are subject to Subpart Ja as of January 1, 2018 if not previously subject.

This is a simple requirement to set all the hydrocarbon flares as being subject to 40 CFR 60 Subpart Ja. It is language brought forward from the requirements of the PM2.5 SIP (Section IX.H.11.g.v.A) in order to maintain consistency between sections. Although the second paragraph of the PM2.5 SIP (IX.H.11.g.v.B) was not similarly brought forward, flare gas monitoring provisions which address the elements of that subsection can be found within each refinery's individual specific requirements of Section IX.H.2 (*see* Item 6.1 below).

5.1 Monitoring, Recordkeeping and Reporting

The new petroleum refinery requirements establish several specific emission limitations. Primarily these limits are monitored continuously – such as the SO_2 CEM on the FCCU or the H_2S monitor on fuel gas. Where continuous monitoring is used, the requirements of IX.H.1.f apply, which incorporates by reference R307-170, 40 CFR 60.13 and 40 CFR 60, Appendix B – Performance Specifications.

Under R307-170, paragraph 170-8 addresses Recordkeeping, while 170-9 addresses Reporting.

The FCCU PM limit is demonstrated by stack test. This stack test requirement is subject to the requirements of IX.H.1.e. In addition, any source with a direct stack emission limitation is subject to the requirements of R307-165.

These conditions are also subject to the general recordkeeping and reporting requirements of IX.H.1.c.

5.2 Discussion of Attainment Demonstration

PM Discussion: While the new PM limit on the FCCU might not appear to directly affect PM10 emissions, this would be incorrect. The limit is derived from the current NSPS (Subpart Ja). Under the NSPS, the assumption was that all particulate captured in the reference test method (Method 5, 5b or 5f) would be considered as PM_{10}. This is still the case, as compliance with the PM limit at the FCCU shall be demonstrated by stack test. Using a method 5 variant stack test allows the test to be overly conservative, as some particulate captured may fall outside the PM_{10} size range, and still be useful for SIP planning purposes. At the same time, it lowers the regulatory burden on the sources, by allowing each source to only have to comply with the requirements of the individual NSPS. The limit is expressed on a 3-hour block average, well below the 24-hour basis of the PM_{10} standard. Stack tests are required every three (3) years, which meets the minimum stack test frequency set by DAQ. Compliance is demonstrated via monitoring and use of emission factors. Stack testing serves to periodically adjust emission factors to account for significant changes in feedstocks, refinery turnarounds, or other large-scale changes that would affect the emission factor. As allowed under R307-165-2, the Director may require stack testing at any time to demonstrate compliance.

SO_2 Discussion: This is a new limitation that did not previously appear in any form in the original SIP. Although the limit is expressed on a 7-day rolling average basis, and therefore longer than the 24-hour PM_{10} standard, SO_2 emissions are eventually converted into sulfates – the particulate form. As this process takes some time to occur, and is not directly dependent on hourly or daily SO2 emissions – but rather on area average SO2 concentrations and relative chemistry – a 7-day rolling average is quite adequate to demonstrate attainment with the standard. This is especially true, given the overall daily SIP Cap – which still controls total SO2 emissions from the entire refinery. The secondary limit, expressed on a 365-day basis simply serves to keep SO2 emissions down over the long run, as well as maintaining consistency with the PM2.5 SIP requirements.

H_2S Discussion: Although the limit appears to be on a much longer averaging period than the 24-hour PM_{10} standard, the rolling 365-day calculation prevents the overall H_2S content from increasing. This in turn keeps the amount of sulfur being sent to each fuel burning device consistently low. This is also a fallback limit, like the SO2 emissions from the FCCU discussed in the previous paragraph. Total SO2 emissions are still controlled by the daily SIP Cap, regardless of the averaging period on fuel gas H2S content.

6.0 New Maintenance Plan – Holly Specific Requirements

The Holly specific conditions in Section IX.H.2 address those limitations and requirements that apply only to the Holly Refinery in particular.

IX.H.2.f.i This condition establishes a source-wide Cap on PM_{10} emissions on a ton per day basis. Emissions are calculated on a filterable plus condensable basis from all sources, each day. This limit is 0.416 tons PM_{10} per day.

The condition also includes the definition of a day as being from midnight until the following midnight. Compliance shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.f.ii This condition establishes a source-wide Cap on NO_x emissions on a ton per day basis. Emissions are calculated from all emission points daily. This limit is 2.09 tons NO_x per day.

This condition includes the same definition of "day" as being from midnight until the following midnight. Compliance shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.f.iii This condition establishes a source-wide Cap on SO_2 emissions on a ton per day basis. Emissions are calculated from all emission points daily. This limit is 0.31 tons SO_2 per day.

This condition includes the same definition of "day" as both of the previous conditions as being from midnight until the following midnight. Compliance shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.f.iv This condition addresses specific fuel sulfur requirements for the refinery, allowing the use of diesel-fired emergency equipment as an exception to IX.H.1.g.iv.

Holly currently has a number of small diesel-fired emergency engines listed in its AO. No specific provision has ever been made to allow for the use of diesel-fired emergency equipment at the refineries – and while it is clear that the provisions of 2.a.M.A{OS} were meant for the burning of liquid fuel in heaters and boilers and not for the application of emergency equipment, such language was not included nor brought forward. This condition (and similar conditions for the other refineries) addresses that oversight.

6.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three conditions is addressed through a variety of methods, depending on the emission point in question. Stack testing, CEMs, parameter monitoring – all are viable options, and have been included in the language of IX.H.2.f.i through IX.H.2.f.iii. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H: 1.e for stack testing, 1.f for CEMs and other continuous monitors, 1.c for recordkeeping and reporting.

Where necessary, additional monitoring, recordkeeping and/or reporting requirements have been directly included in the language of IX.H.2.f to address specific concerns. One example would be the use of leveling gauges on all fuel oil tanks to determine daily fuel oil consumption.

No specific monitoring, recordkeeping or reporting is required for IX.H.2.f.iv, as this condition serves merely as a specific exception to the general refinery requirement prohibiting the burning of liquid fuel oils. Such exception is authorized under the language of IX.H.1.g.iv itself.

Flare gas monitoring requirements – under subsection IX.H.11.g.v.B of the PM2.5 SIP, each refinery, including Holly, is required to install and operate a flare gas recovery system or equivalent flare gas minimization process. This system needs to limit hydrocarbon flaring below 14,160 standard cubic meters (m3) (500,000 standard cubic feet (scf)) above the baseline established by the procedure outlined in 40 CFR 60.103a(a)(4). As the specific requirements of IX.H.11.g.v.B were not brought forward into the new maintenance plan, each refinery is required to include monitoring for flare gas such that total flare gas flow rate can be recorded on a daily basis, the daily flare gas recovered for fuel gas processing can be recorded, and an estimate of daily flare gas emissions can be made. All flaring emissions are included in the daily emission Caps, and monitoring of flare gas flows satisfies both the requirements of demonstrating compliance with the daily Caps as well as subsection IX.H.11.g.v.B.

6.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of daily (24-hr) source-wide emissions from the Holly refinery is identical to the method used in during the 1991/1992 timeframe of the original SIP. However, several key differences exist:

1. Emissions in the new maintenance plan are lower than in the original SIP

As is shown above in Table 3, the daily SIP Caps have dropped for all pollutants of concern [PM_{10}, SO_2 and NO_x]. The annual emissions have also dropped for all pollutants, although no annual Cap is required.

2. All emission units/emission points are included in the new maintenance plan

The original SIP was based on a concept of "SIP Cap sources", where only certain specific sources were included as contributing toward the emission total for a particular pollutant. Other sources, such as the flares or the compressors, would be specifically excluded from counting towards this total. This would even be spelled out by a specific requirement in the original SIP. The new maintenance plan eliminates this concept by simply stating that all sources are included, and that the emission "Caps" apply source-wide.

3. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan includes both filterable and condensable PM_{10} emissions. The 24-hour source-wide PM_{10} limit listed in IX.H.2.f.i clearly states that condensable emissions are included from all sources, and the emission factors listed in that condition include values for condensable emissions.

7.0 Interim Emission Limits and Operating Practices

When the new maintenance plan is issued and made effective, the existing SIP Sections IX.H.1-4 will be repealed and replaced. On a federal level, the currently approved 1991 PM10 State

Implementation Plan will be superseded with the newest version. As many of the requirements and emission limits in IX.H.1 and IX.H.2 for the refineries have implementation dates of January 1, 2018 or January 1, 2019, an "implementation gap" could have potentially existed between the effective date of the SIP and those future compliance dates.

In order to address this concern, new Subsection IX.H.4, titled Interim Emission Limits and Operating Practices has been established to serve as a bridge between these two periods. For all other point sources listed in IX.H.2 and IX.H.3 the limits apply upon approval by the Utah Air Quality Board of the PM_{10} Maintenance Plan.

There are two main sections of IX.H.4: a set of general requirements that applies to all petroleum refineries in or affecting any PM10 nonattainment/maintenance area, and then a set of specific requirements for each of the four listed refineries in IX.H.2 (BWO, Chevron, Holly and Tesoro). Both the general and specific requirements of IX.H.4 are designed to be used in conjunction with all of the requirements of IX.H.1. As these limits and operating practices are to serve only during the brief period between SIP issuance and January 1, 2019, only a bare minimum of requirements were retained. All requirements are specifically pulled from each source's latest AO, such that the source will continue to remain in compliance; however, each requirement also matches the 2005 State-only SIP. As the control technology for the sources listed in this subsection is installed and operational, the terms and conditions listed in IX.H.1 and IX.H.2 becomes applicable and those limits then replace the limits in this subsection.

For Holly the following conditions and limitations apply during the interim period:

A. Refinery General – retention of the 9.8 kg of SO2 per 1,000 kg of coke burn-off from any Catalytic Cracking unit limit.
B. Combined emissions of filterable PM10 from all combustion sources, shall be no greater than 0.44 tons per day.
C. Combined emissions of SO2 from all sources shall be no greater than 4.714 tons per day.
D. Combined emissions of NOx from all sources shall be no greater than 2.20 tons per day.

Each limit has an associated compliance demonstration method and averaging period.

8.0 Implementation Schedule

The daily (24-hour) emission Caps are effective as of January 1, 2019. This schedule is dictated by the original RACT requirements established under the $PM_{2.5}$ SIP of 2014 (IX.H.11-13). In order to allow for construction, installation, shakedown and initial testing of the new equipment, this January 1, 2019 date was selected. Demonstration of attainment under the new PM_{10} maintenance plan is also set as January 1, 2019.

The provisions of IX.H.1.a-f (the General Requirements) are effective immediately upon implementation of the new maintenance plan. Those listed in IX.H.1.g (Refineries) have variable implementation dates depending on the specific provision. Some take effect immediately, while others take effect on January 1, 2018 or on January 1, 2019. Again, these dates exactly match those listed in the $PM_{2.5}$ section of the SIP (IX.H.11).

In order to address the possibility of an "implementation gap" from occurring, interim emission limits and operating practices have been established. These interim requirements are found in Subsection IX.H.4 of the new maintenance plan. For complete details on these requirements, please see Item 7.0 above.

9.0 References

Evaluation Report – Holly Refinery

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information